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Baseload wind energy: modeling the competition between gas turbines and compressed air energy storage for supplemental generation

Jeffery B. Greenblatt[a,*], Samir Succar[b], David C. Denkenberger[c], Robert H. Williams[b], Robert H. Socolow[d]

[a]Environmental Defense, Oakland, CA, USA
[b]Princeton Environmental Institute, Princeton University, Princeton, NJ, USA
[c]Department of Civil, Environmental and Architectural Engineering, University of Colorado, Boulder, CO, USA
[d]Department of Mechanical and Aerospace Engineering, Princeton University, Princeton, NJ, USA

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Abstract

The economic viability of producing baseload wind energy was explored using a cost-optimization model to simulate two competing systems: wind energy supplemented by simple- and combined cycle natural gas turbines ("wind + gas"), and wind energy supplemented by compressed air energy storage ("wind + CAES"). Pure combined cycle natural gas turbines ("gas") were used as a proxy for conventional baseload generation. Long-distance electric transmission was integral to the analysis. Given the future uncertainty in both natural gas price and greenhouse gas (GHG) emissions price, we introduced an effective fuel price, p_{NGeff}, being the sum of the real natural gas price and the GHG price. Under the assumption of p_{NGeff} = \$5/GJ (lower heating value), 650 W/m^2 wind resource, 750 km transmission line, and a fixed 90% capacity factor, wind + CAES was the most expensive system at ¢6.0/kWh, and did not break even with the next most expensive wind + gas system until p_{NGeff} = \$9.0/GJ. However, under real market conditions, the system with the least dispatch cost (short-run marginal cost) is dispatched first, attaining the highest capacity factor and diminishing the capacity factors of competitors, raising their total cost. We estimate that the wind + CAES system, with a greenhouse gas (GHG) emission rate that is one-fourth of that for natural gas combined cycle plants and about one-tenth of that for pulverized coal plants, has the lowest dispatch cost of the alternatives considered (lower even than for coal power plants) above a GHG emissions price of \$35/tC$_{equiv.}$, with good prospects for realizing a higher capacity factor and a lower total cost of energy than all the competing technologies over a wide range of effective fuel costs. This ability to compete in economic dispatch greatly boosts the market penetration potential of wind energy and suggests a substantial growth opportunity for natural gas in providing baseload power via wind + CAES, even at high natural gas prices.

Keywords: Wind energy; Compressed air energy storage (CAES); Greenhouse gas emissions

1. Introduction

Wind energy has enjoyed robust growth in recent years, averaging 30% per year increase in installed capacity since 1992 (EWEA, 2004). Driving this growth has been a combination of factors: a twofold drop in capital costs between 1992 and 2001 (Junginger and Faaij, 2003), and a number of government initiatives designed to encourage wind energy. Global installed wind capacity stood at 59 GW at the end of 2005 (GWEC, 2006; WWEA, 2006), generating about 1.0% of global electricity consumption. Projections indicate that capacity may rise to nearly 200 GW by 2013 (BTM Consult ApS, 2004), with the potential to grow much larger (e.g., Archer and Jacobson, 2005).

Fueling much of the government support for wind energy are environmental concerns. While it is widely recognized that the impact of wind energy on the environment is not zero, the significant impacts of air pollution, water consumption and the depletion of natural resources are much lower than those of current fossil fuel technologies (European Commission, 2003). Moreover, its

*Corresponding author. Tel.: +1 510 4572210; fax: +1 510 6580630.
E-mail address: jgreenblatt@environmentaldefense.org (J.B. Greenblatt).

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potential to provide large amounts of electricity without direct GHG emissions[1] has now become perhaps the major driving force for wind energy. Numerous energy analysts predict that the inevitable limitation of GHG emissions, whether via an emissions trading system, emissions taxes, or some other mechanism, will further encourage the growth of wind energy by making it economically competitive with fossil fuels, without direct subsidy.

However, wind is an intermittent resource. When wind power output falls, grid operators must be able to provide sufficient power from other sources to satisfy demand. At small market penetrations, such shortfalls can be met by existing voltage regulation, load following, and spinning reserve resources, with negligible additional system cost (Kelly and Weinberg, 1993). But at larger penetrations (e.g., 20%), this incremental cost per unit wind energy produced becomes significant, of the order of 1–1.5¢/kWh (ILEX Energy Consulting, 2002), due to the need for supplemental generating capacity.[2] This "intermittency penalty" does not include the higher cost of wind energy itself. Wind energy penetration levels of >20% are already a reality in Denmark and several Spanish and German provinces (BTM Consult ApS, 2004; Holttinen 2005). Moreover, many European countries and at least one US state (California) have set goals of 20% or more electrical energy from renewables in the next two decades (Goswami, 2004; Hinrichs-Rahlwes, 2004; Parent, 2004; Timms, 2004; Steineger, 2005), and much of this energy would be supplied by wind (BTM Consult ApS, 2004).

Another important consideration at high levels of wind energy deployment is the distance between wind resource and demand. In the US, much of the high-quality wind resource is located in the sparsely populated Great Plains (Elliott et al., 1991),[3] while in Asia, there are vast resources in Mongolia (Elliott et al., 2001) and remote parts of northern and western China, as well as offshore (Lew et al., 1998; CREIA, 2004). As the EU exhausts its onshore potential, it is looking both offshore and at sites in Russia, northwestern Africa, and Kazakhstan (Czisch, 2004). Many of these locations require long transmission distances (up to 4500 km) to bring the electricity to market, making transmission capital an important additional cost for wind energy.

The full cost of wind energy, including proper treatment of the issues of intermittency and remoteness of wind resources, must be carried out in order to understand the true potential of wind in meeting future electricity needs, giving attention to the need for supplemental generation to guarantee system reliability (ILEX Energy Consulting, 2002; DeCarolis and Keith, 2006) and strengthened or expanded transmission capacity needed to exploit remote wind resources.

This paper explores the economic viability of two alternative strategies for transforming wind energy from an intermittent resource into a baseload electricity source. We have simulated the three-way economic competition among combined cycle (CC) natural gas turbines, wind with a combination of simple cycle (SC) and CC gas plants, and wind partnered with compressed air energy storage (CAES). Long-distance transmission was modeled for the wind and CAES systems; however, it was assumed that the gas plants (SC and CC) would be located nearby to demand because they are generally unconstrained by the location of physical resources.[4]

Natural gas turbines are well-suited for addressing wind intermittency issues because of their fast ramping rates and low capital costs. Other supply technologies, such as hydroelectric and coal plants, can also be used, though coal's slower ramping rates generally limit its ability to supplement wind energy. Complementary intermittent generation, such as solar PV, and demand-side management, such as interruptible loads, are also important possibilities.

Energy storage presents still another strategy for providing baseload electricity from wind. A number of storage technologies exist which are economical on various timescales (EPRI-DOE, 2003), but only two technologies—pumped hydroelectric storage and compressed air energy storage (CAES)—are cost-effective at the large temporal scales (several hours to days) needed to complement wind energy that we investigate here. Conversion of wind electricity into another storable energy carrier, such as hydrogen or thermal energy, is also a possibility. In this paper, we consider only CAES.

CAES is commercially available storage technology that is currently used primarily to store low-cost off-peak power for sale during periods when the electricity is more valuable. To date, three CAES plants have been built and operated in the world: a 290 MW facility in Germany (Huntorf, which became operational in 1978), a 110 MW facility in the United States (McIntosh, which went into operation in 1991), and a 25 MW R&D facility in Italy (Sesta, which ran for a few years in the early 1990s) (R. Schainker, pers. commun., 2006). Several more plants

[1]Total life cycle GHG emissions from wind energy are not zero (see, e.g., Denholm et al., 2005). However, compared with electricity plants that burn fossil fuels, the GHG emissions from wind turbines are extremely low.

[2]One way of explaining the growth of this incremental cost is that the "capacity credit" for intermittent wind capacity has its maximum economic value at very small grid penetration. This credit, estimated to be the wind capacity times it capacity factor (~1/3) times the economic value of the dispatchable (usually fossil) capacity displaced ($/kW), diminishes monotonically with increasing grid penetration.

[3]There may also be significant offshore resources in shallow waters of the eastern and western US coasts (Musial and Butterfield, 2004).

[4]The availability of adequate natural gas supply does represent a physical constraint that could affect how many gas plants are built. However, it should be relatively easy to site such plants near load centers because they require little space and have relatively low air pollutant emission levels. Placing a gas plant at the remote site confers no economic advantage to the system, unless siting or operation and maintenance (O&M) costs are lower, because transmission losses are incurred. By contrast, locating a CAES plant near the wind park allows the use of a smaller transmission line, imparting a significant economic advantage.

are under development, including a 260 MW facility in Iowa, and a 2700 MW facility in Ohio (EPRI-DOE, 2003; K.Holst, private commun., 2006). Although no CAES facility has yet been built with the explicit purpose of enabling baseload wind power generation, the Huntorf plant is used for leveling the variable power from numerous wind turbines in Germany (EPRI-DOE, 2003), and the Iowa facility is a proposed wind CAES system for delivering power during peak periods (Wind, 2002).

CAES units couple turbomachinery to energy storage in the form of compressed air. The compressed air can be stored underground in a solution-mined salt cavity, in a mined hard rock cavity, or in an aquifer; aboveground storage in tanks is also possible but is much more costly. The turbomachinery is basically a gas turbine in which the air compression and expansion steps are separated temporally. Commercially available CAES involves inter-cooling the air during compression and storing it at close to ambient temperature. The compressed air recovered from storage is heated[5] by burning a fuel such as natural gas[6] in it, and the combustion products are expanded in the turbine to produce electricity.

A typical CAES unit might consume 0.67 kWh of electricity to compress air for storage and later burn ~4200 kJ of natural gas in compressed air recovered from storage to generate each kWh of electricity. For such a unit the estimated electrical round-trip efficiency would be in the range 77–89%.[7] The underground storage volume required would typically be $\sim 2.4\times10^7\,\mathrm{m}^3$ for each week of storage required per GW of CAES capacity.[8] Hard caverns can be excavated to volumes of $\sim 10^7\,\mathrm{m}^3$ (roughly $250\,\mathrm{m}^3$ diameter), so that GW-scale CAES units would require multiple caverns. For aquifer storage, assuming a layer thickness of 10 m and effective porosity[9] of 0.2, a 1 GW CAES unit with a week's storage capacity would occupy an area of $\sim 12\,\mathrm{km}^2$.

Using only two supplemental generation technologies for backing up wind greatly simplified the model. We believe this approach captures most of the important contrasts between the fill-in generation and energy storage approaches to dealing with intermittency. However, our choice of the natural gas CC as the baseload power technology displaced might not adequately capture the implications of the full range of baseload options that wind systems might displace, which also include coal, nuclear and hydroelectric plants—an issue that we return to later in the paper.

In real electricity markets, a significant part of the intermittent wind energy production might be absorbed by existing ancillary services in a more economical way than by utilizing dedicated fill-in power or energy storage as modeled here.[10] However, this is not the case when long-distance transmission is involved, because of the need to maximize the use of expensive transmission capital. Moreover, at the high wind energy penetration levels posited in this model, ancillary services would probably be insufficient to absorb intermittent wind generation. Under these conditions, our model is likely to be a good approximation of the way wind intermittency will be handled in the future, and its simplicity and transparency are key advantages.

An advantage of considering only SC, CC and CAES is that they all burn the same fuel, so the effects of changing fuel prices and GHG prices are folded into one variable, the effective fuel price (p_{NGeff}), which we define as

$$p_{\mathrm{NGeff}}(\$/\mathrm{GJ}) = p_{\mathrm{NG}}(\$/\mathrm{GJ}) + p_{\mathrm{GHG}}(\$/\mathrm{tC_{equiv.}}) \cdot C_{\mathrm{NG}}(\mathrm{tC_{equiv.}}/\mathrm{GJ}), \quad (1)$$

where p_{NG} is the actual market price of natural gas, p_{GHG} is the price of emitting GHGs (CO_2 plus equivalent amounts of other gases), and C_{NG} is the total GHG content of natural gas, equal to $18.0\,\mathrm{kgC_{equiv}}/\mathrm{GJ}$, including typical upstream emissions[11]—so that each $\$100/\mathrm{tC_{equiv.}}$ of GHG price contributes \$1.8/GJ to the effective fuel price.

This work builds upon several previous studies, beginning with the groundbreaking work of Cavallo and colleagues (Cavallo, 1995–1997; Cavallo and Keck, 1995) who first explored wind parks coupled with CAES and connected via transmission lines to distant demand

[5]If an attempt were made to expand the air in the turbine without heating, system components would freeze.

[6]Therefore, the CO_2 emissions from a CAES plant are not zero. However, the use of carbon-neutral fuels may be feasible (Denholm, 2006). In principle, it is also possible to store the heat of compression separately from the air, avoiding the need for fuel altogether (Bullough et al., 2004).

[7]The CAES electrical round-trip efficiency is difficult to specify precisely. We estimate a range of efficiencies for a unit consuming 4220 kJ of natural gas for each kWh of electricity recovered from storage based on assigning to the natural gas consumed an equivalent electricity value. If one assumes that the equivalent electricity from natural gas is based on simple cycle efficiency ($HR_{\mathrm{SC}} = 9400\,\mathrm{kJ/kWh}$), then the total equivalent electricity input is 1.12 kWh, resulting in a CAES electrical round-trip efficiency of 89%. Alternatively, if one assumes combined cycle efficiency ($HR_{\mathrm{CC}} = 6700\,\mathrm{kJ/kWh}$), then total electricity input is 1.30 kWh, and the CAES electrical round-trip efficiency is 77%.

[8]This estimate is based on the McIntosh CAES unit in the United States, which stores air in a salt cavern at pressures ranging between 45 and 72 atm. The McIntosh plant, which has a discharge capacity of 110 MW (5.05 kg of air per kWh) that can be sustained for up to 26 h, requires $0.14\,\mathrm{m}^3$ of storage volume per kWh of electricity discharged.

[9]Effective porosity is the product of actual porosity and "saturation" (fraction of pores that can be displaced by air); in the above example, we have assumed a porosity of 0.3 and a saturation of 2/3 (C. Christopher, pers. commun., 2006).

[10]There are two possible complementary applications of CAES to wind systems: short-term power regulation (up to several hours) and long-term storage (several days). We model only the latter application in this paper, because we focus exclusively on baseload energy. A fuller analysis that includes the first application should increase the attractiveness of CAES.

[11]The CO_2 content of natural gas is approximately 13.64 kgC/GJ (higher heating value, HHV) or 15.16 kgC/GJ (lower heating value, LHV) (EIA, 2005). Upstream greenhouse emissions add an additional 2.84 kg $\mathrm{C_{equiv.}}$/GJ (LHV) (Wang, 1999). The GHG emissions associated with manufacturing of capital components were not included. Energy units are heretofore expressed using the LHV convention, unless otherwise specified.

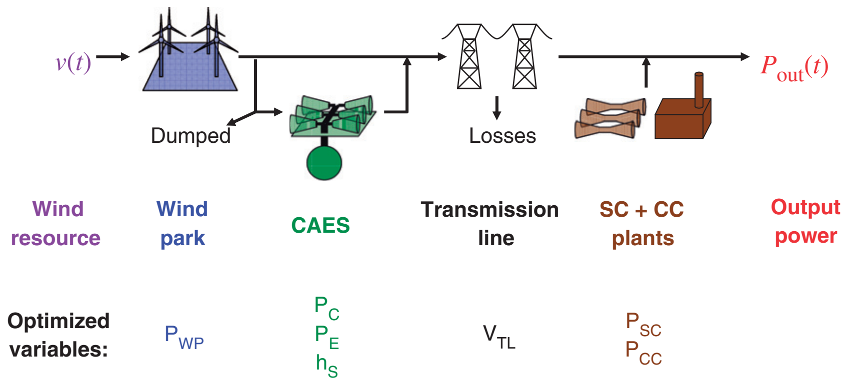

Fig. 1. Schematic diagram of model. Variable definitions are given in Table 3.

centers.[12] More recently, ILEX Energy Consultants (2002) calculated the intermittency penalty for various future levels of wind energy penetration on the UK electric grid. Keith and Leighty (2002) analyzed the comparative economics of transporting wind energy from North Dakota to Chicago via electric transmission versus hydrogen pipeline. The Iowa Association of Municipal Utilities analyzed the economics of a wind park coupled with CAES in Iowa (Wind, 2002), and Ridge Energy Storage, LLC (Desai and Pemberton, 2003; Lower Colorado River Authority, 2003) analyzed the economics of wind parks with CAES in West Texas. Denholm et al. (2005) analyzed costs and total lifecycle GHG emissions of generic baseload wind/CAES systems with long-distance transmission. DeCarolis and Keith (2006) modeled the competition among wind parks, SC, CC and CAES for multiple wind sites in the US Great Plains, transmitting electricity to Chicago.

2. Model description

We model the system shown schematically in Fig. 1, which delivers 2.0 GW of baseload power at the end of a long, high-voltage transmission line.[13] Base case model parameters are listed in Table 1, and equations are given in Table 2.

Modeling begins with an hourly time series of synthetic wind speeds $v(t)$, (see below) and from these calculates the hourly wind park power, which is split among directly transmitted power, power sent to the CAES compressor (if present), and "dumped" (curtailed) power. The CAES unit compresses air into a storage volume up to a specified reservoir capacity. The CAES expander utilizes this compressed air, along with natural gas, to generate electricity whenever the wind park power falls below the (constant) demand level. Transmitted electricity undergoes power-dependent losses. SC and CC gas turbine plants (if present) are then dispatched to make up any shortfall, up to the required capacity factor.

The wind + CAES system is designed to be a baseload power unit with sufficient storage capacity to deliver power at the transmission line output capacity while not allowing system output to fall below this level during more than 10% of the recorded hours. This design criterion both determines the amount of storage and dictates that the CAES expander capacity P_E equals P_{TL}, the transmission line capacity. Alternative approaches for designing a wind + CAES system are also feasible—such as requiring 100% availability of power from the system (DeCarolis and Keith, 2006). The rationale for our design choice was twofold: (1) except for unscheduled outages, the system would have the capability to satisfy demand even during times of insufficient wind power output (as long as the CAES cavern is not depleted); and (2) the system has considerable operational flexibility—to the extent that, given a modest capability to forecast fluctuations in wind speed and electricity demand, the 10% downtime could be mostly scheduled during times of lowest demand. This approach both addresses grid stability concerns and exploits the flexible dispatch capability of CAES. Thus, it is possible to hold the system to a standard consistent with baseload operation and still allow the model to exploit the unique attributes of energy storage.

The wind speed time series was constructed with an autoregressive algorithm (McFarlane et al., 1994) producing a Weibull distribution of frequencies, and a time series autocorrelation function that decayed exponentially with time constant $\theta/2$, where θ was an input parameter set to 30 h in the base case.[14] We assumed a wind park of sufficient size ($\geqslant 2$ GW) that intra-hour variations in power can be averaged, and an hourly time series can be used. This time step is also compatible with the ramping capabilities of SC, CC and CAES plants. No diurnal or seasonal variations in average wind speed were modeled. The wind park is assumed to be made up of pitch-regulated

[12] Several studies of wind parks coupled with CAES significantly predate the Cavallo work (e.g., Zlokovic, 1969) but they did not consider long-distance transmission.

[13] Such high-capacity transmission lines are needed to make long-distance transmission cost-effective.

[14] This choice of θ represents a typical midrange value from the 51 data sets we examined.

Table 1
Base case parameters of the model

Parameter	Symbol	Base value	Units	Reference
Major parameters				
Demand (constant)	P_d	2	GW	
Capital charge rate[a]	CCR	11	%/yr	
System capacity factor	CF	90	%	
Transmission distance	D_{TL}	750	km	
Base effective fuel price[b]	p_{NGeff}	5	\$/GJ	
Average wind speed (class 4)[c]	v_{avg}	8.22	m/s	Malcolm and Hansen (2002)
Autocorrelation time[d]	θ	30	h	
Wind park base cost[e]	$C_{WP,0}$	700	\$/kW	Neij, 1999; Junginger and Faaij, 2003
CAES compressor cost[f,g]	C_C	170	\$/kW	EPRI-DOE (2003)
CAES expander cost[f,g]	C_E	185	\$/kW	EPRI-DOE (2003)
CAES storage cost[g,h]	C_S	1	\$/kWh	EPRI-DOE (2003)
SC capital cost[i]	C_{SC}	240	\$/kW	Gas Turbine World (2003)
CC capital cost[i]	C_{CC}	580	\$/kW	Dillon et al. (2004)
TL converter cost	c_{conv}	50	\$/kW	Hauth et al. (1997)
TL tower + cable (line) cost	c_{line}	491	\$/kV km	Empirical fit to Hauth et al. (1997)
TL right-of-way cost[j]	c_{ROW}	988	\$/m km	Empirical fit to Hauth et al. (1997)
Minor parameters				
Hours per year	HY	8760	h/yr	
Time step	Δt	1	h	
Simulation period	T	50,000	h	
GHG intensity of natural gas[b,k]	C_{NG}	18.0 (55.6)	kgC$_{equiv.}$/GJ (GJ/tC$_{equiv.}$)	
Air density	ρ_{air}	1.225	kg/m^3	Malcolm and Hansen (2002)
Weibull shape factor	K	2		Malcolm and Hansen (2002)
Wind turbine rotor diameter	D	100	m	Malcolm and Hansen (2002)
Wind turbine hub height	h	120	m	Malcolm and Hansen (2002)
Wind turbine base rated power	$P_{rate,0}$	3.50	MW	Malcolm and Hansen (2002)
Wind turbine cut-in speed	v_{in}	3.0	m/s	Malcolm and Hansen (2002)
Wind turbine rated speed (at v_{avg})	$v_{rate,0}$	12.33	m/s	Malcolm and Hansen (2002)
Wind turbine rated speed ratio	r_{rate}	1.5		Malcolm and Hansen (2002)
Wind turbine efficiency[l]	C_p	39	%	Malcolm and Hansen (2002)
Array efficiency below rating	α_0	86	%	Denkenberger (2005)
Wind turbine fixed block coefficient[m]	f_{fix}	29	%	Denkenberger (2005)
Wind turbine thrust block coefficient[m]	f_{thr}	32	%	Denkenberger (2005)
Wind turbine torque block coefficient[m]	f_{tor}	9	%	Denkenberger (2005)
Wind turbine power block coefficient[m]	f_{pow}	30	%	Denkenberger (2005)
Wind turbine thrust block exponent[m]	e_{thr}	0.7		Denkenberger (2005)
Wind turbine torque block exponent[m]	e_{tor}	1.4		Denkenberger (2005)
Wind turbine power block exponent[m]	e_{pow}	3		Denkenberger (2005)
CAES minimum power ratio	r_{min}	5	%	
CAES energy output/input ratio	E_o/E_i	1.50		EPRI-DOE (2003)
CAES balance of plant cost ratio[f]	R_{BOP}	63	%	EPRI-DOE (2003)
CAES heat rate[b]	HR_{CAES}	4220	kJ/kWh	EPRI-DOE (2003)
SC heat rate[b]	HR_{SC}	9400	kJ/kWh	
CC heat rate[b]	HR_{CC}	6700	kJ/kWh	EPRI-DOE (2000)
SC maximum derating[n]	R_{SC}	20	%	Nakhamkin et al. (2004)
CC maximum derating[n]	R_{CC}	13	%	
Wind park fixed O&M (levelized replacement cost)	$C_{WP,F}$	15	\$/kW yr	Malcolm and Hansen (2002)
Wind park variable O&M cost	$C_{WP,V}$	0.8	¢/kWh	Malcolm and Hansen (2002)
CAES fixed O&M	$C_{CAES,F}$	4	\$/kW yr	EPRI-DOE (2003)
CAES variable O&M	$C_{CAES,V}$	0.3	¢/kWh	EPRI-DOE (2003)
SC fixed O&M	$C_{SC,F}$	10.8	\$/kW yr	Dillon et al. (2004)
SC variable O&M	$C_{SC,V}$	0.13	¢/kWh	Dillon et al. (2004)
CC fixed O&M	$C_{CC,F}$	10.8	\$/kW yr	Dillon et al. (2004)
CC variable O&M	$C_{CC,V}$	0.13	¢/kWh	Dillon et al. (2004)
TL number of circuits	N_C	1		Hauth et al. (1997)
TL number of poles	N_P	2		Hauth et al. (1997)
TL number of converters	N_{conv}	2		Hauth et al. (1997)
TL converter loss (per station)	l_{conv}	1	%	Hauth et al. (1997)
TL thermal power coefficient	p_{th}	6.030	kW/kV^2	Empirical fit to Hauth et al. (1997)
TL line loss coefficient	l_{line}	1.029	% kV^3/kW km	Empirical fit to Hauth et al. (1997)
TL right-of-way width coefficient	w_{ROW}	10.79	M MW$^{-1/6}$	Empirical fit to Hauth et al. (1997)

Table 1 (*continued*)

Parameter	Symbol	Base value	Units	Reference
Internal parameters				
Wind speed	v		m/s	
Time	t		h	
Number of wind turbines	N_{turb}			
TL rated power	P_{TL}		MW	
TL peak-to-ground voltage	V_{TL}		kV	
Wind park capacity factor	CF_{WP}		%	
CAES capacity factor	CF_{CAES}		%	
SC capacity factor	CF_{SC}		%	
CC capacity factor	CF_{CC}		%	

[a]Obtained from EPRI accounting rules (EPRI, 1993) with the following assumptions: construction period 2.5 years (3 equal payments), inflation rate 2%/yr, book life 30 years, tax life 20 years, modified accelerated capital recovery system (MACRS) depreciation for tax purposes, corporate tax rate 38.2%, property taxes and insurance 2%/yr, nominal return on equity 10%/yr, nominal return on debt 6.5%/yr, equity/debt share 45%/55%, real discount rate 5%/yr (after-tax weighted real average cost of capital).

[b]Thermal content stated in LHV basis.

[c]Extrapolated from 10 m reference Class 4 wind speed (5.77 m/s) using 1/7 scaling exponent to assumed hub height of 120 m.

[d]Autocorrelation time used is modal non-infinite value obtained from analysis of 51 wind speed time series from the US Great Plains (Milligan, pers. commun., 2003; HPRCC (High Plans Regional Climate Center), 2003; NCDC (National Climatic Data Center), 2004; UWIG (Utility Wind Interest Group), 2004).

[e]This turbine cost is a conservative estimate for 2020, based on two projections (Neij, 1999; Junginger and Faaij, 2003).

[f]Costs determined from information provided by EPRI-DOE (2003) and commercial vendors (N. Desai, pers. commun., 2003; R. Hanes, pers. commun., 2003).

[g]Note that although these costs have subsequently been revised upward (EPRI-DOE, 2004), we felt the original costs better represented "*N*th plant" costs. However, the sensitivity study includes the effects of higher CAES capital and storage costs (see Tables 4 and 5).

[h]Storage cost for mined salt dome.

[i]Capital cost is scaled by 1.47 to account for balance of plant cost.

[j]Assuming cost of land is $4000/acre, as suggested in Hauth et al. (1997).

[k]Natural gas carbon dioxide content (15.16 kgC/GJ) (EIA, 2005) including upstream GHG emissions (2.84 $kgC_{equiv.}$/GJ) (Wang, 1995).

[l]The C_p for the 1.5 MW turbine in Malcolm and Hansen (2002) was used here.

[m]Cost data from Malcolm and Hansen (2003) were fitted to a four-component model that grouped costs according to their observed power-law trends with rated power (Denkenberger, 2005).

[n]Simple cycle value ($\pm$10% output over the course of a year) from Nakhamkin et al. (2004). For combined cycle value, we reduced this value by 1/3 to account for the much less temperature-sensitive combined cycle output.

wind turbines having a constant turbine efficiency C_p below rated speed (v_{rate}), and with an array efficiency coefficient $\alpha(v)$ that is constant up to $v = v_{rate}$ and increases toward unity at higher wind speeds (Denkenberger, 2005).

Our CAES model parameters were obtained from several sources (Westinghouse Electric Corporation, 1995; Crotogino et al., 2001; EPRI-DOE, 2003; N. Desai, pers. commun., 2003; R. Hanes, pers. commun., 2003). The system was treated for the most part as a "black box," shown in Fig. 2, with a compressor that adds air to storage until the reservoir is full, and an expander that generates electricity from stored air as needed until the storage reservoir is empty. The performance characteristics were based on a two-stage, intercooled compressor with a pressure ratio of ~50–100, and a two-stage expander turbine with heat recovery for which 4220 kJ of natural gas is consumed per kWh of CAES output. For the base case, the ratio of electricity output to electricity input (E_o/E_i) is 1.5. It was assumed that the compressor and expander trains were composed of ~10 units each, in order to maintain efficient operation for the plant as a whole down to 5% of the rated CAES output (r_{min}), with shut-down thereafter. For the base case wind + CAES system (see Section 3), this implied compressor and expander units of ~250 and ~210 MW, respectively. For simplicity it was assumed that the air recovered from the storage reservoir is delivered at constant pressure to the turbine expander.[15]

For transmission, a high-voltage direct current (HVDC) line is superior to an alternating current line at distances of interest for this study ($\geqslant$750 km). Costs varied with transmission voltage V_{TL}, rated transmission power P_{TL}, transmission length D_{TL}, and some other minor parameters, using equations fitted to data in Hauth et al. (1997); see Tables 1 and 2. The model optimum used voltages of

[15]For aquifers and hard rock that contains a pressure-compensating water column, the reservoir pressure remains constant, so that the assumption accurately describes operation. For salt caverns and dry hard rock reservoirs, the reservoir pressure increases as air is added, so that the air recovered from storage can either be delivered at variable pressure to the turbine or it can be throttled and delivered at constant pressure. Although there is a slight savings in compression energy with variable pressure operation, the required cavity size would be much greater (Karalis et al., 1985).

Table 2
Model equations

Parameter	Symbol	Equation	Base value	Units	Reference
Weibull scale factor	c	$v_{avg}/\Gamma(1+1/k)$	9.28	m/s	
Weibull probability	$p(v)$	$(k/c)(v/c)^{k-1}\exp[-(v/c)^k]$			
Wind power flux	f_W	$(\rho_{air}/2)c^3\Gamma(1+3/k)$	650	W/m^2	
Wind speed autocorrelation function	$C(t)$	$\int v(t'+t)v(t')\,dt' = e^{-2t/\theta}$			
Wind turbine swept area	A	$(\pi/4)D^2$	7850	m^2	
Wind turbine array spacing	A_{turb}	$50D^2$	0.5	km^2	Elliott et al. (1991)
Wind turbine cut-out speed	v_{out}	$3.5v_{avg}$	28.8	m/s	Malcolm and Hansen (2002)
Wind turbine rated speed	v_{rate}	$v_{avg}r_{rate}$	12.33	m/s	
Wind turbine power	$P_{turb}(v)$	$AC_p\rho_{air}v^3/2,\ v_{in}\leqslant v<v_{rate}$		MW	
		$P_{rate},\ v_{rate}\leqslant v<v_{out}$			
		0, otherwise			
Wind turbine rated power	P_{rate}	$AC_p\rho_{air}v_{rate}^3/2$	3.50	MW	
Wind turbine array efficiency	$\alpha(v)$	$\alpha_0,\ v\leqslant v_{rate}\alpha_0(v/v_{rate})^3,\ v_{rate}<v\leqslant v_{rate}/\alpha_0^{1/3}1,\ v>v_{rate}/\alpha_0^{1/3}$			Denkenberger (2005)
Wind park power	$P_{out}(v)$	$N_{turb}\alpha(v)P_{turb}(v)$		MW	
Wind park rated power	P_{WP}	$N_{turb}P_{rate}$		GW	
Transmission line thermal rated power	P_{th}	$p_{th}V_{TL}^2N_CN_P$		GW	Empirical fit to Hauth et al. (1997)
Transmission line right-of-way width	W_{ROW}	$w_{ROW}(P_{th}N_P)^{1/6}$		m	Empirical fit to Hauth et al. (1997)
Transmission losses	P_{loss}	$l_{line}D_{TL}P_{TL}^2CF/(V_{TL}^3N_CN_P)+l_{conv}N_{conv}P_{TL}$		MW	Empirical fit to Hauth et al. (1997)
Wind park capital cost[a]	C_{WP}	$C_{WP,0}(P_{rate,0}/P_{rate})$	700	\$/kW	Denkenberger (2005)
		$[f_{fix}+f_{thr}(v_{rate}/v_{rate,0})^{ethr}+f_{tor}(v_{rate}/v_{rate,0})^{etor}+f_{pow}(v_{rate}/v_{rate,0})^{epow}]$			
CAES capital cost	C_{CAES}	$(1+R_{BOP})(C_CP_C+C_EP_E)/P_E+C_Sh_S$		\$/kW	
SC derated capital cost	C_{SC}'	$C_{SC}(1+R_{SC})$	290	\$/kW	
CC derated capital cost	C_{CC}'	$C_{CC}(1+R_{CC})$	655	\$/kW	
Transmission line capital cost	C_{TL}	$c_{conv}N_{conv}+D_{TL}[c_{line}V_{TL}(N_CN_P)^{1/2}+c_{ROW}W_{ROW}]/P_{TL}$		\$/kW	Empirical fit to Hauth et al. (1997)
Wind park annual cost	A_{WP}	$P_{WP}(C_{WP}CCR+C_{WP,F}+C_{WP,V}CF_{WP}HY)$		\$/yr	
CAES annual cost	A_{CAES}	$P_E[C_{CAES}CCR+C_{CAES,F}+(C_{CAES,V}+p_{NGeff}HR_{CAES})\ CF_{CAES}HY]$		\$/yr	
Transmission line annual cost	A_{TL}	$P_{TL}C_{TL}CCR$		\$/yr	
SC annual cost	A_{SC}	$P_{SC}[C'_{SC}CCR+C_{SC,F}+(C_{SC,V}+p_{NGeff}HR_{SC})CF_{SC}HY]$		\$/yr	
CC annual cost	A_{CC}	$P_{CC}[C'_{CC}CCR+C_{CC,F}+(C_{CC,V}+p_{NGeff}HR_{CC})CF_{CC}HY]$		\$/yr	
System cost of energy	COE	$(A_{WP}+A_{CAES}+A_{TL}+A_{SC}+A_{CC})/(P_dCF\cdot HY)$		¢/kWh	

[a]See footnote ‘m’ under Table 1.

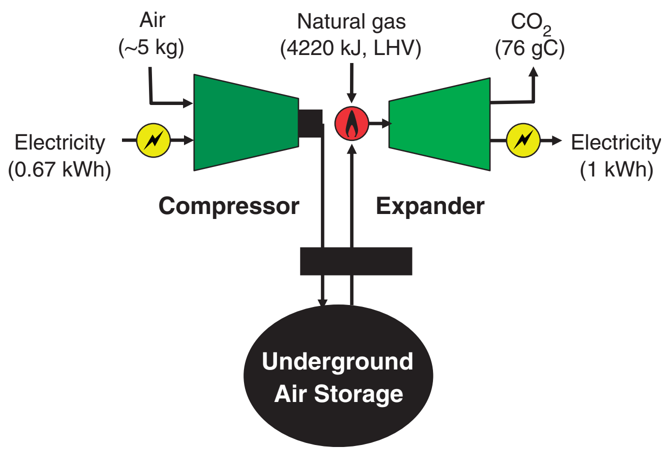

Fig. 2. CAES schematic.

approximately 550–750 kVDC in order to minimize losses; see Section 3.

Our base case assumed a set of costs and performance characteristics that might be realized for wind farms coming on line by 2020. The average wind turbine was assumed to have a rated output of 3.5 MW, rotor diameter of 100 m, hub height of 120 m, and cost of \$700/kW, consistent with recent projections (Neij, 1999; Junginger and Faaij, 2003). All costs were expressed in 2002 inflation-adjusted US dollars. Class 4 winds were assumed, with average wind speed v_{avg} at hub height of 8.22 m/s and power flux f_W of 650 W/m^2 (assuming a Weibull shape parameter of $k = 2$). The capital charge rate *CCR* of 11%/yr was based on the assumption of stable government policy for renewable energy, resulting in a low-risk private investment environment with moderate rates of return on equity.[16] Our base case natural gas price is \$5/GJ. The CAES storage reservoir cost of \$1/kWh used in our base case assumed a salt cavern; the use of aquifers is expected to be considerably less expensive (~\$0.1/kWh) because no excavation is required; hard rock excavation costs are far greater (~\$30/kWh) (EPRI-DOE, 2003).

3. Results and discussion

Seven system variables were freely varied[17] in order to minimize the total levelized cost of energy (*COE*): wind park rated power (P_{WP}), CAES compressor power (P_C), CAES expander power (P_E), CAES storage duration (h_S), transmission line voltage (V_{TL}), SC rated power (P_{SC}) and CC rated power (P_{CC}). We found that, as a function of effective fuel price p_{NGeff}, the optimization favored three configurations with unchanging characteristics (as specified by the system variables), rather than continuously varying characteristics.[18] This observation allowed us to represent the optimal system by one of these three sets of variables to a high degree of accuracy, and calculate the optimal *COE* for a given p_{NGeff} from these variables. A plot of *COE* versus p_{NGeff} for each of the three systems is shown in Fig. 3. The system with the lowest *COE* at $p_{NGeff} =$ \$5/GJ (¢4.5/kWh) is composed exclusively of CC gas turbines and is called the "gas" system. The next most expensive system at this p_{NGeff} value (¢5.1/kWh) is composed of a wind park supplemented by mostly CC, with a small amount (10%) of SC gas turbine capacity in the base case. It is called the "wind + gas" system, and its *COE* line crosses the gas *COE* line near \$7.1/GJ. Finally, the most expensive system at $p_{NGeff} =$ \$5/GJ (¢6.0/kWh) is composed of a larger wind park, CAES plant, and no gas plant. It is called the "wind + CAES" system, and its *COE* line crosses the wind + gas *COE* line near \$9.0/GJ. The optimal system is indicated in Fig. 3 by the dotted line highlighting the least costly option at each value of p_{NGeff}.

We call the values of p_{NGeff} at which the optimal system changes the "effective fuel entry prices," and define p^{wind}_{NGeff} as the entry price of wind + gas, and p^{CAES}_{NGeff} as the entry price of wind + CAES.

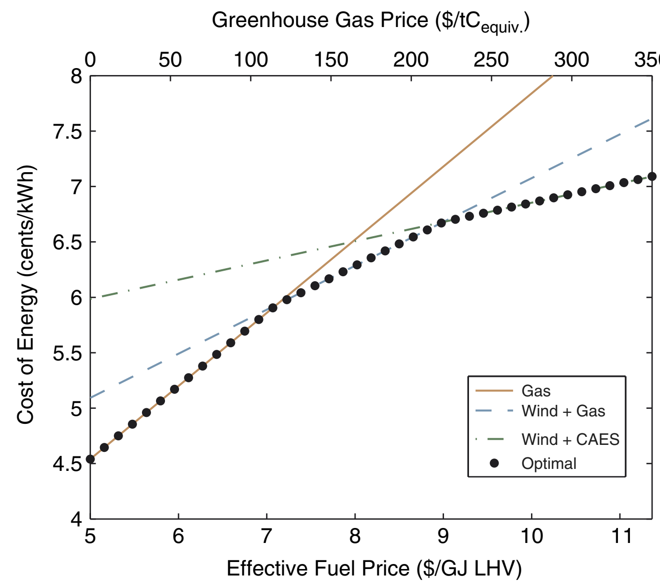

Fig. 3. Cost of energy (*COE*) versus effective fuel price (p_{NGeff}). The GHG price p_{GHG}, assuming a real fuel price $p_{NG} =$ \$5/GJ, is shown on the top axis. Four data sets are shown. Solid line: gas. Dashed line: wind + gas. Dashed/dotted line: wind + CAES. Black points: optimal (lowest *COE*) system.

[16] The *CCR* used was obtained using EPRI accounting rules (EPRI, 1993) for private financing with parameters summarized in footnote (a) of Table 1. This rate may be compared to private financing rates of 8-12%/yr in the literature (Malcolm and Hansen, 2002; Milborrow, 2005; DeCarolis and Keith, 2006).

[17] While it was possible in principle to vary all seven variables simultaneously in the optimization, this was not done in production runs in order to increase convergence: the CAES expander capacity (P_E) was forced to equal the transmission line capacity (P_{TL}), and the SC and CC capacities (P_{SC} and P_{CC}) were optimized separately, outside the main optimization algorithm.

[18] The one exception to this was $P_{SC}/(P_{SC} + P_{CC})$ for the wind + gas system, which varied continuously with p_{NGeff}, from 10% (at $p_{NGeff} =$ \$5/GJ) to 2.5% (at $p_{NGeff} =$ \$11.3/GJ). However, setting this ratio constant had almost no effect on cost.

By historical standards the effective entry gas prices highlighted in Fig. 3 are very high, which suggests poor economic prospects for baseload wind. Consider average gas prices seen by electric generators in the United States. As recently as 2002 this gas price averaged \$3.8/GJ. But since then it has climbed to \$5.5/GJ in 2003, \$6.0/GJ in 2004, and \$7.2/GJ for the first nine months of 2005. It is expected that the gas price will eventually decline somewhat from current high levels, but not to the low levels of the past. The most recent forecast of the US Energy Information Administration (EIA, 2006) is that the natural gas price seen by the average US electric generator will be \$5.4/GJ in 2020 rising to \$6.3/GJ in 2030, suggesting that our base case assumption about the gas price 2020+ may be unrealistically low. However, we explore the impact of higher gas prices on our results in Section 3.1, and find little change in the conclusions reached other than a shift in entry prices.

The equivalent GHG entry prices, assuming an actual fuel price of \$5/GJ, are \$120/tC$_{\text{equiv.}}$ and \$220/tC$_{\text{equiv.}}$, respectively, and are labeled $p_{\text{GHG}}^{\text{wind}}$ and $p_{\text{GHG}}^{\text{CAES}}$. These may be compared with recent GHG prices in the voluntary US market (\$3–7/tC$_{\text{equiv.}}$) (Chicago Climate Exchange, 2005) and in the EU market (\$100–130/tC$_{\text{equiv.}}$) (PointCarbon, 2005). It is widely expected that the GHG price will need to be \$100/tC$_{\text{equiv.}}$ or higher in order to induce significant GHG mitigation; this is supported by macroeconomic modeling of the Kyoto Protocol and its extensions (Manne and Richels, 1999) as well as detailed technology assessments, such as the cost-competition between electricity from coal with CO_2 venting versus coal integrated gasification combined cycle (IGCC) with carbon capture and storage (CCS) (Williams, 2004)

Changes in slope of the optimal *COE* versus p_{NGeff} curve in Fig. 3 occur where system lines cross, and these crossing points are associated with changes in GHG emissions per unit energy for the optimal system. A roughly twofold decrease in GHG emissions occurs in moving from gas (120 gC$_{\text{equiv.}}$/kWh) to wind + gas (73 gC$_{\text{equiv.}}$/kWh), and another roughly twofold decrease occurs in moving to wind + CAES (32 gC$_{\text{equiv.}}$/kWh). This stepwise decrease in slope with p_{NGeff} reflects decreased consumption of natural gas, and proportionate increase in wind energy per kWh provided by the optimal system. Note that these emissions rates may be compared with emissions from a typical coal steam-electric plant (276 gC$_{\text{equiv.}}$/kWh), a SC natural gas plant (170 gC$_{\text{equiv.}}$/kWh), or a coal IGCC + CCS plant (53 gC$_{\text{equiv.}}$/kWh)[19] (Williams, 2004).

Values of system variables and some other details are given in Table 3, while *COEs* disaggregated by component are presented in Table 4 and Fig. 5. Here we highlight the physical scale of components and capital costs for each system.

The gas system, located entirely at the demand site, is made up of 2.00 GW of CC gas turbines and no SC turbines and requires a capital investment of \$1.32 billion.

For the wind + gas system, the wind park consists of 617 wind turbines of 3.5 MW each, for a rated (maximum) capacity of 2.16 GW. Assuming a turbine spacing of 0.5 km^2 per turbine,[20] the wind park occupies an area of 309 km^2. The 750 km transmission line, rated at 540 kV, has an input capacity of 2.16 GW capacity; after losses, the delivered capacity is 2.00 GW. Also included in the system at the end of the transmission line are 1.80 GW of CC gas turbines and 200 MW of SC turbines. The total required capital investment is \$3.28 billion, comprised of \$1.51 billion for the wind park, \$520 million for the transmission line, \$1.19 billion for the CC plant and \$60 million for the SC plant.

The wind park for the wind + CAES system is much larger, made up of 1318 turbines producing 4.61 GW rated capacity and occupying 659 km^2. The CAES system consists of 2.53 GW compressor capacity, 2.08 GW expander capacity, and an underground storage reservoir of 352 GWh (169 h of storage at rated expander capacity), occupying a volume of 5.0×10^7 m^3. The 750 km transmission line has a rating of 750 kV and 2.08 GW input capacity; after losses, the delivered capacity is 2.00 GW. There are no gas turbines at the demand site. The total capital cost is \$5.54 billion, comprised of \$3.23 billion for the wind park, \$1.68 billion for the CAES plant, and \$630 million for the transmission line.

Fig. 4 shows power duration curves for the three systems. A power duration curve indicates the maximum power output as a function of the number of hours per year that the system runs. (There are 8760 h in a year.)

For the gas system (panel 1), the power duration curve is very simple: the plant runs at full power for ~7900 h (90%) of the year.

For the wind + gas system (panel 2), the wind park delivers full power for only ~1500 h (17%), dropping rapidly as the number of hours increases; above ~7900 h, no power is produced. Thus, the combined SC + CC capacities are also set equal to demand. The total capacity factor of the wind park (average wind park power divided by wind park rated power) is 39%, of which 2% is lost during transmission. The shortfall in energy is made up for by SC (2%) and CC (51%).

For the wind + CAES system (panel 3), there is more than twice as much installed wind power as for wind + gas. This is because most of the "surplus" wind power (power in excess of demand, defined as $P_{\text{WP}}-P_{\text{TL}}$), which is available for ~3100 h (35%) of the year, is stored by the CAES system. About 7% of the surplus energy is "dumped" (curtailed) in the base case when the storage reservoir is full. The directly transmitted wind energy has a capacity factor of 55%. The CAES expander adds another

[19]This emissions rate is also comparable to that from BP's proposed "decarbonized" natural gas CC plant (BP, 2005) when upstream emissions are included (Wang, 1999).

[20]Typical array spacing is 50 squared rotor diameters, arranged as a 5×10 or 7×7 diameter matrix.

Table 3
Optimization results

	Symbol	Units	Gas	Wind + Gas	Wind + CAES
Optimized variables					
Wind park rated power	P_{WP}	GW	0	2.160	4.612
(Number of turbines—3.5 MW each)	(N_{WT})			(617)	(1,318)
CAES compressor rated power	P_C	GW	0	0	2.530
CAES expander rated power	P_E	GW	0	0	2.082
CAES storage duration	h_S ($P_E h_S$)	h (GWh)	0	0	169 (352)
Transmission line voltage	V_{TL}	kV	0	537	746
Simple cycle rated power	P_{SC}	GW	0	0.200	0
Combined cycle rated power	P_{CC}	GW	2.000	1.800	0
Output variables					
Transmission line rated power (before losses)	P_{TL}	GW	0	2.160	2.082
Capacity factors (relative to annual demand):					
Wind park (generated)	CF_{WP}	%	0	38.7	82.6
Wind park (transmitted)	$CF_{WP,trans}$	%	0	38.7	54.8
Wind park (stored via CAES)	$CF_{WP,stor}$	%	0	0	25.9
Wind park (dumped)	$CF_{WP,dump}$	%	0	0	1.9
CAES output	CF_{CAES}	%	0	0	39.0
Transmission line (initial)	CF_{TL}	%	0	38.7	93.8
Transmission line (loss)	$CF_{TL,loss}$	%	0	2.4	3.8
Simple cycle	CF_{SC}	%	0	2.2	0
Combined cycle	CF_{CC}	%	90.0	51.5	0
Total	CF	%	90.0	90.0	90.0
GHG emissions rate	E_{GHG}	gC$_{equiv.}$/kWh	120.0	72.8	31.6
Cost of energy[a]	COE	¢/kWh	4.540	5.092	5.985
Entry effective fuel price	p_{NGeff}	\$/GJ	—	7.083	8.962
Entry GHG price[b]	P_{GHG}	\$/tC$_{equiv.}$	—	115.7	220.1
Cost of energy (at entry p_{NGeff})	COE_{NGeff}	¢/kWh	—	5.929	6.680

[a]At $p_{NGeff} = \$5/\text{GJ}$.
[b]At $p_{NG} = \$5/\text{GJ}$.

39%, and 4% is lost during transmission. (Note that in order to capture all of the excess wind power, the CAES compressor installed power (P_C) must match the surplus wind installed power.)

For wind + CAES, the wind park produces, through either direct transmission or via CAES, 72% of yearly demand,[21] or 80% of produced energy. In contrast, in the wind + gas system, only 36% of yearly demand, or 40% of produced energy, is generated by the wind park. These percentages (80% and 40%) can be viewed as the maximum economical wind penetration on the baseload portion of an electric grid employing the storage and fill-in generation approaches, respectively. The baseload portion of electrical demand supplies the majority of annual energy consumed, so the baseload penetration level is a good approximation of the penetration level for the grid as a whole. Using CAES therefore greatly expands the penetration potential of wind on an electric grid.

The compressor-to-expander power ratio (P_C/P_E) in our optimization, 1.22, is quite large compared with those designed to capture off-peak energy for price arbitrage (0.2–0.7) (Crotogino et al., 2001; Wind, 2002; Bell et al., 2003; EPRI-DOE, 2003). For these latter systems, cost optimization leads to a low P_C/P_E ratio because the compressor can store energy during long off-peak periods (two-thirds or more of the time), so its installed power can be smaller than that of the expander, which must deliver back the stored energy only during the short peak period. For baseload wind + CAES, however, the compressor must capture all the surplus wind energy, which exceeds the installed power of the expander in our optimal configuration.

The duration of CAES storage h_S is also large, 169 h in our base case, as compared to 2–30 h for peak-shifting designs. This is due to the significant differences in system objectives as discussed above. It should be pointed out, however, that h_S is strongly dependent on our parameter assumptions, varying by a factor of four up or down over the plausible range of parameter values (see Section 3.1 below). However, even at the low end of its plausible range, h_S is still large compared with peak-shifting values. Our result is in agreement with Cavallo (1996), who used the same an autoregressive algorithm as ours but with $\theta = 10$ h instead of 30 h: we both obtained $h_S \approx 85$ h when the capacity factor is 90%. The only study that found a larger storage duration than our base case was Cavallo and Keck (1995), who examined the effect of a seasonal variation of $\pm 25\%$ in wind power flux, and found 250 h to be optimal in the 90% capacity factor case.

[21]Assuming 80% round-trip electrical efficiency of the CAES system.

Table 4
Disaggregation of the cost of energy (*COE*) for the three optimized systems, assuming base case parameters and $p_{\mathrm{NGeff}} = \$5/\mathrm{GJ}$. Transmission loss cost and sensitivities to some system parameters are also shown. Note for wind resource parameters ($v_{\mathrm{avg}}, k, \theta$), system is reoptimized in each case

	Gas		Wind + Gas		Wind + CAES	
	¢/kWh	%	¢/kWh	%	¢/kWh	%
Wind park						
Capital	0.000	0.00	1.029	20.21	2.159	36.08
Fixed O&M	0.000	0.00	0.200	3.93	0.421	7.03
Variable O&M	0.000	0.00	0.334	6.56	0.685	11.45
CAES						
Plant capital	0.000	0.00	0.000	0.00	0.889	14.85
Storage capital	0.000	0.00	0.000	0.00	0.235	3.93
Fixed O&M	0.000	0.00	0.000	0.00	0.051	0.85
Variable O&M	0.000	0.00	0.000	0.00	0.039	0.65
Fuel	0.000	0.00	0.000	0.00	0.841	14.06
Transmission						
Converter capital	0.000	0.00	0.142	2.78	0.137	2.28
Line/ROW capital	0.000	0.00	0.214	4.21	0.286	4.78
Losses	0.000	0.00	0.121	2.38	0.243	4.06
SC						
Capital	0.000	0.00	0.040	0.78	0.000	0.00
Fixed O&M	0.000	0.00	0.017	0.33	0.000	0.00
Variable O&M	0.000	0.00	0.003	0.06	0.000	0.00
Fuel	0.000	0.00	0.111	2.18	0.000	0.00
CC						
Capital	0.919	20.24	0.807	15.84	0.000	0.00
Fixed O&M	0.158	3.48	0.139	2.72	0.000	0.00
Variable O&M	0.130	2.86	0.073	1.43	0.000	0.00
Fuel	3.333	73.42	1.863	36.59	0.000	0.00
Total *COE*[a]	4.540	100.00	5.092	100.00	5.985	100.00
Sensitivities						
GHG emissions cost ($p_{\mathrm{GHG}} = \$100/\mathrm{tC}_{\mathrm{equiv.}}$)	+1.200	+26.43	+0.728	+14.30	+0.316	+5.28
Production tax credit (PTC)[b]	0.000	0.00	–0.796	–15.63	–1.530	–25.59
PTC and $C_{\mathrm{WP}} = \$1000/\mathrm{kW}$	0.000	0.00	–0.355	–6.97	–0.605	–10.10
$v_{\mathrm{avg}} = 7.53\,\mathrm{m/s}$ ($f_{\mathrm{W}} = 500\,\mathrm{W/m^2}$, wind power class 3)	0.00	0.0	+0.191	+3.76	+0.468	+7.82
$v_{\mathrm{avg}} = 8.81\,\mathrm{m/s}$ ($f_{\mathrm{W}} = 800\,\mathrm{W/m^2}$, wind power class 5)	0.00	0.0	–0.118	–2.31	–0.128	–2.14
$k = 1.5$[c]	0.00	0.0	+0.048	+0.95	+0.214	+3.58
$k = 3.0$[c]	0.00	0.0	+0.056	+1.10	+0.181	+3.03
$\theta = 10\,\mathrm{h}$	0.00	0.0	0.00	0.0	–0.145	–2.43
$\theta = 60\,\mathrm{h}$	0.00	0.0	0.00	0.0	+0.347	+5.79

[a]Totals may not match component sums due to rounding.
[b]Here we assume that the production tax credit (PTC, ¢1.9/kWh) applies to all wind electricity reaching the transmission line, equal to directly transmitted energy plus 80% of stored CAES energy.
[c]These runs performed while keeping the mean wind speed constant at the base case value (8.22 m/s).

3.1. Sensitivity studies

Our base case represents only one possible set of parameter assumptions, and many of these parameters affected the system variables, cost of energy, and effective fuel price at which wind parks and/or CAES would be built in lieu of gas. In this section, we explore the most important parameters affecting *COE* and p_{NGeff}. (Unless otherwise indicated, the *COE* is reported for $p_{\mathrm{NGeff}} = \$5/\mathrm{GJ}$).

We present the sensitivity studies in the context of disaggregations of the *COE* for the three optimized base case systems presented in Table 4 and Fig. 5. For each system component, the costs of capital, operations and maintenance (O&M) and, where applicable fuel and transmission losses are shown. Table 4 also shows the sensitivities of the *COE* to several parameters. Note that, for each of the sensitivities relating to the three wind resource parameters (v_{avg}, k and θ), the system was reoptimized.

The sensitivity to changes in cost components can be gleaned from the base case disaggregated costs by an appropriate scaling of the *COE* share, assuming no changes in overall system variables (which we have verified empirically to be a good approximation for changes of $\sim<\pm 20\%$ in component costs). Thus, for wind + gas, the wind park capital comprises 20% (¢1.0/kWh) of overall *COE*, so a 20% increase in capital cost (to \$840/kW)

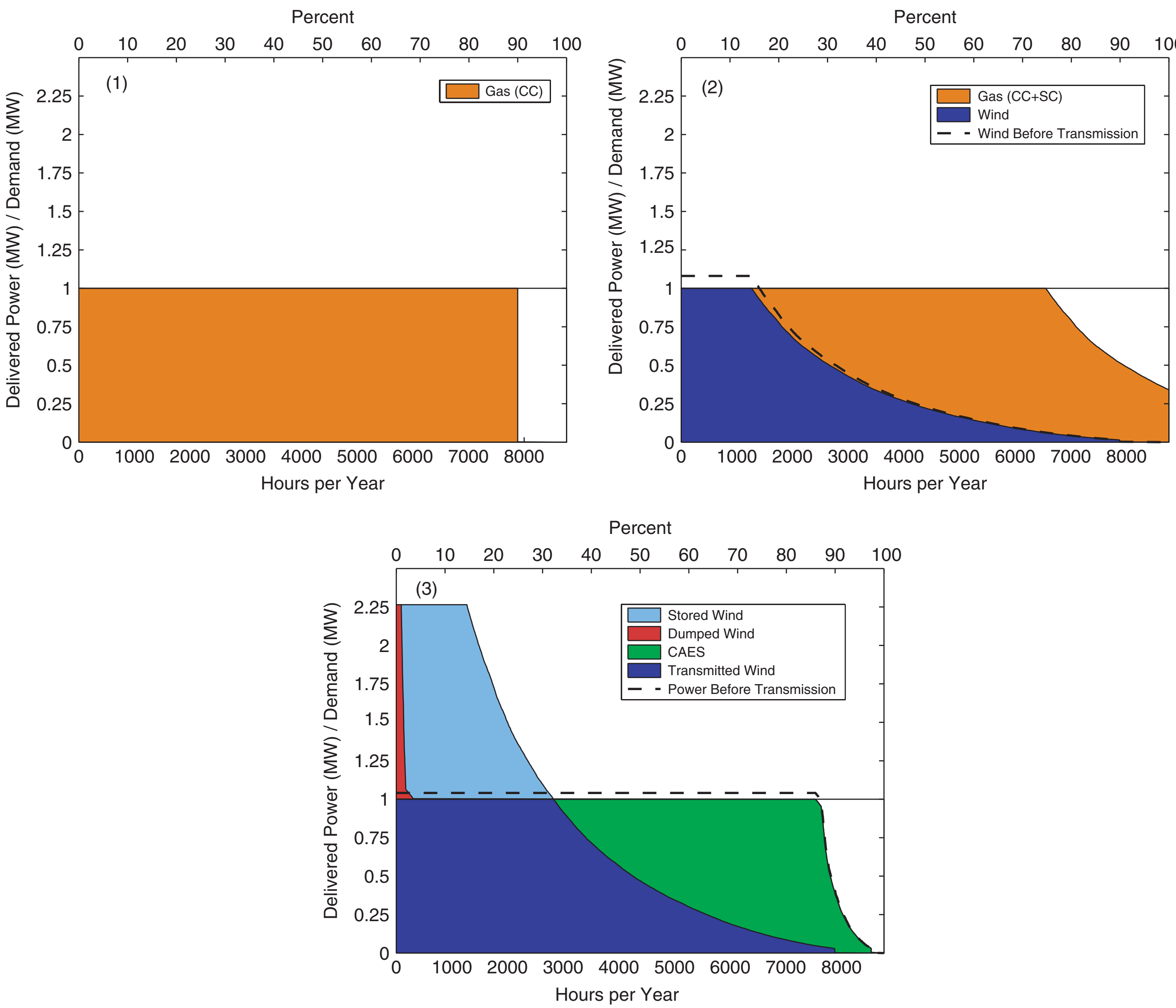

Fig. 4. Power duration curves for the three optimized base case systems. Areas indicate energy produced. Remote power before transmission losses is indicated by thick broken line. Panel 1: Gas Panel 2: Wind + gas. Panel 3: Wind + CAES.

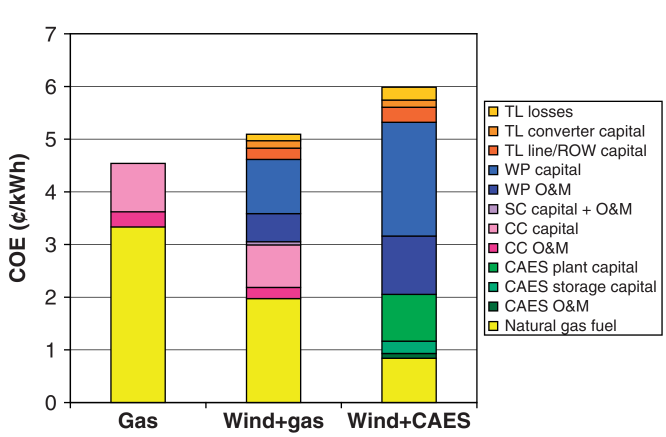

Fig. 5. Disaggregation of the cost of energy (*COE*) for the three optimized base case systems.

translates into a *COE* increase of 4% (¢0.2/kWh). For wind + CAES, where the wind park capital cost is larger share of the total, the impact on the COE of a 20% increase is approximately double.

Changes in the capital charge rate (*CCR*) have a relatively large impact on the *COE* for the more capital-intensive systems, because that parameter affects all capital costs. Thus, a 20% increase in *CCR* (to 13.2%/yr) will increase the *COE* by 12% (¢0.7/kWh) for wind + CAES (for which capital accounts for 58% of the total *COE* in the base case) but only 4% (¢0.2/kWh) for gas (for which capital accounts for only 20% of the *COE* in the base case).

Similarly, when the capital components are a small share of total *COE*, changes in the fuel or O&M costs will have a larger effect on the *COE*. For instance, fuel use comprises

73% of the *COE* in the gas base case, whereas it is only 14% for wind + CAES. Thus, a 20% increase in fuel price (to \$6/GJ) increases the *COE* of the gas system by 15% (¢0.7/kWh) but only 3% (¢0.2/kWh) for wind + CAES.

Missing from the above discussion is consideration of possible differential market risk among the three systems modeled. The gas system is most vulnerable to fuel price (and, to a lesser extent, GHG price) risk, whereas the wind + gas system and, particularly, the wind + CAES system, are more exposed to technological risk. However, the assumptions we have made here are that, by 2020, both fuel price and technology risks are relatively low, thus justifying the use of low *CCR* values for all technologies. If one wished to apply a different set of risk assumptions, a straightforward way to estimate the resulting economic competition would be to apply different *CCR* values among the technology components, and calculate new *COE* values using the data in Table 4.

In many countries, economic incentives exist to help encourage the growth of wind energy. These incentives can take the form of fixed rate contracts, tax credits, or other mechanisms. In the US, the production tax credit (PTC) has been in place for several years[22] to help defray the cost of producing electricity from wind. It is currently ¢1.9/kWh. Applying this credit to generated wind electricity reduces the base case *COE* of wind + gas by ¢0.8/kWh, and of wind + CAES by ¢1.5/kWh.[23] However, it is unlikely that the PTC, which was designed to help subsidize expensive capital, would still be in effect when the cost of wind turbines reaches \$700/kW. Therefore, applying the PTC with current wind turbine capital costs (assumed \$1000/kW), the base case *COE* of wind + gas is reduced by ¢0.4/kWh, and of wind + CAES by ¢0.6/kWh; see Table 4 for details. These savings are of the same order of magnitude as other changes discussed above.

An important trade-off exists between transmission distance (D_{TL}) and wind power class (expressed as v_{avg} or f_W). We see in Table 4 that the transmission line and right-of-way (ROW) contributions to the *COE*, which scale with distance, are 4% for wind + gas and 5% for wind + CAES, for the base case of $D_{TL} = 750$ km and $f_W = 650\,\mathrm{W/m^2}$ (class 4 winds at 120 m). The losses are approximately equally split between fixed (converter) and distance-dependent (line) contributions for 750 km in each case, and so add 1% and 2% to the *COE* for wind + gas and wind + CAES, respectively. Thus, for a 1500 km transmission line, the *COE* would be 5% (¢0.3/kWh) and 7% (¢0.4/kWh) higher, respectively. For no transmission line, all transmission capital and losses, including the fixed converter costs, disappear, so the *COE* decreases by 9% (¢0.5/kWh) and 11% (¢0.7/kWh).The effect of changing the wind resource by one wind power class ($\pm 150\,\mathrm{W/m^2}$) is also shown in Table 4. It is asymmetric about the base case, with a larger change in *COE* occurring when lowering the wind class. Thus, lowering the wind resource by one power class has approximately the same effect on *COE* as increasing the transmission distance by ~500 km for wind + gas, and ~900 km for wind + CAES, while increasing the wind resource by one power class is equivalent to decreasing the transmission distance by ~300 and ~400 km, respectively.[24] This trade-off is often not appreciated when estimating wind energy costs, as higher wind classes tend to be more remote from demand centers; thus, some of the advantage of higher wind classes is nullified by higher transmission costs.

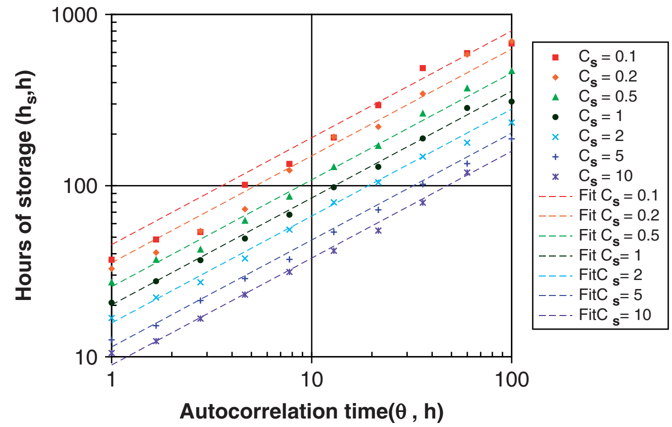

Fig. 6. Duration of storage (h_S) versus autocorrelation time (θ) for several values of storage cost (C_S). Note axes are both logarithmic. Fits (see text) shown by dashed lines.

Another important trade-off involves the impacts of the autocorrelation time (θ) and the cost of storage (C_S) on the optimal CAES storage duration (h_S). Fig. 6 shows h_S versus θ for a number of values of C_S. We found that the dependence of h_S on θ and C_S could be fit very well by

$$h_S(\theta, C_S) = 20.1\,\theta^{0.62} C_S^{-0.35}, \tag{2}$$

where h_S and θ are expressed in hours, and C_S is in \$/kWh.[25] The fits are shown in Fig. 6. For our base case of $\theta = 30$ h and $C_S = \$1/\mathrm{kWh}$, we obtain $h_S = 166$ h, close to the observed 169 h. Decreasing θ or increasing C_S by a factor of three reduced h_S by 49% and 32%, respectively. The h_S showed little dependence on changes in other parameters. The *COE* increased markedly (by more than ¢2/kWh) when θ and/or C_S increased to the highest values in their respective ranges, but there was relatively little cost savings (less than ¢0.4/kWh) when decreasing these values.

We have discussed the system sensitivities to *COE* above, but have not considered the resulting changes in the entry

[22]However, the only PTC that the US Congress has supported has expired every two years, creating an uneven investment environment that has had a negative impact on the growth of wind power in the US.

[23]Here we assume that the credit applies to all wind electricity reaching the transmission line, equal to directly transmitted energy plus 80% of stored CAES energy.

[24]For an HVDC transmission system. If instead an HVAC system were used (which is less expensive at short distances), the equivalent decrease in transmission distance would be smaller.

[25]The data point at $\theta = 100$ h and $C_S = \$10/\mathrm{kWh}$ was omitted from the fit, as the model did not always build wind + CAES even at $p_{NGeff} = \$12.2/\mathrm{GJ}$, the highest value explored.

prices $p_{\mathrm{NGeff}}^{\mathrm{wind}}$ and $p_{\mathrm{NGeff}}^{\mathrm{CAES}}$. Because changes in cost tend to affect only the intercepts of the *COE* versus p_{NGeff} lines, and because the slopes for all three systems are relatively shallow, small changes in *COE* intercepts translate into large changes in entry prices. For instance, as discussed above, a 20% increase in wind park capital cost increases the *COE* of wind + gas by 4% and of wind + CAES by 8%. However, the corresponding increases in $p_{\mathrm{NGeff}}^{\mathrm{wind}}$ and $p_{\mathrm{NGeff}}^{\mathrm{CAES}}$ are 11% (\$0.8/GJ) and 12% (\$1.1/GJ), respectively. The impacts of a 20% increase in *CCR* are even larger: 15% (\$1.0/GJ and \$1.4/GJ, respectively). Table 5 shows the sensitivities in entry prices p_{NGeff} (and p_{GHG}) for plausible changes in many parameters. The common observation is that relatively modest changes in parameter values can have large effects, as much as $\pm$\$1/GJ or greater in some cases. If we reasonably assume that all the parameters listed in Table 5 are uncoupled from one another and may take on any value in the displayed range, then we can obtain a simple estimate of the total uncertainty in p_{NGeff} by adding average sensitivities in quadrature. The results are $\Delta p_{\mathrm{NGeff}}^{\mathrm{wind}} = \pm\$2.2/\mathrm{GJ}$ and $\Delta p_{\mathrm{NGeff}}^{\mathrm{CAES}} = \pm\$4.1/\mathrm{GJ}$, or $\Delta p_{\mathrm{GHG}}^{\mathrm{wind}} = \pm\$120/\mathrm{tC_{equiv.}}$ and $\Delta p_{\mathrm{GHG}}^{\mathrm{CAES}} = \pm\$230/\mathrm{tC_{equiv.}}$. However, it should be pointed out that changes in $p_{\mathrm{NGeff}}^{\mathrm{wind}}$ and $p_{\mathrm{NGeff}}^{\mathrm{CAES}}$ tend to be in the same direction, so the large uncertainty does not invalidate the conclusion that wind + gas is more economical than wind + CAES over a wide range of parameter assumptions. We therefore assign relatively little certainty to the absolute value of the entry prices, emphasizing instead the relative values, and recognize that the true entry prices will depend sensitively on many parameter assumptions, some of which will be determined by technical progress, while others will be determined by both local and global economic conditions.

3.2. Dispatch cost considerations

It was assumed for the base case analysis that all competing options are baseload systems operated at 90% capacity factor. Although this assumption simplified the comparative analysis, the capacity factors would differ among the options in a real energy market. A key parameter determining the capacity factor of any option under market conditions is the "dispatch cost": the sum of all short-run marginal costs (fuel cost + variable O&M cost + GHG cost). Moreover, the capacity factor for each option depends on the dispatch cost of not just the energy systems studied, but also the dispatch costs for all the other energy systems on the grid as well. For a given set of power generating systems, the grid operator determines the capacity factors of these systems by calling first on the system with the least dispatch cost. Under this condition, deployment in sufficient quantity of the technology with the least dispatch cost can lead to a reduction of the capacity factors, and thus an increase in the *COE*s of the competing options on the system.

As a result of the increases in natural gas prices in the US noted earlier this phenomenon has resulted in reducing capacity factors for natural gas CC plants originally designed for baseload operation to average utilization rates in the range 30–50% where coal plants are available to compete in dispatch (Thambimuthu et al., 2005).

In principle, this downward pressure on capacity factors for options with high dispatch costs could be avoided with "take-or-pay" contracts that require the generator to provide a specified fixed amount of electricity annually. But uncertainties about future fuel prices, technological change, and future electricity demand make such contracts rare. So plants are typically designed to be able to compete in economic dispatch.

To illustrate the implications of the dispatch rule for the relative "real world" economics of the systems studied here, Table 6 shows for both $p_{\mathrm{GHG}} = \$0/\mathrm{tC_{equiv.}}$ and \$100/$\mathrm{tC_{equiv.}}$ dispatch costs for the base case systems and three coal options with which these systems are likely to compete on many grids, e.g., in the US—existing coal plants and new coal IGCC plants with both CO_2 vented and CO_2 capture and storage (CCS). A GHG price of \$100/$\mathrm{tC_{equiv.}}$ is singled out because that is essentially the price at which CCS becomes cost-competitive for new coal power plants, and thus represents a threshold price for a climate mitigation policy targeting deep reductions in GHG emissions.

Table 6 shows that, unlike the other options, the dispatch costs for both the wind + gas and wind + CAES systems vary from low values of ¢0.8–0.9/kWh when only electricity is being provided by wind power to much higher maximum values when the wind is not blowing and the supplemental power system (gas turbine or CAES expander) is operating. The maximum dispatch costs shown for the wind systems are the relevant ones that determine whether a 90% capacity factor can be defended in the market.

It is beyond the scope of the present study to calculate the market capacity factors for the options studied—which would require specification of the entire generation system and the demand profile for the customers served by the grid. However, one can acquire an understanding of the prospects for defending a 90% capacity factor from the information presented in Table 6.

Consider a hypothetical situation where there are only two competing 2 GW supply systems on the grid (wind + CAES plus one other from Table 6) contending for a 90% capacity factor and a total grid demand (e.g., at night) of only 2 GW. The market price at that time would be the lesser of the dispatch costs of these two options. The system with the higher dispatch cost would shut-down completely then to avoid losing money, thereby reducing its annual average capacity factor and increasing its COE. Table 6 shows that at $p_{\mathrm{GHG}} = \$0/\mathrm{tC_{equiv.}}$, wind + CAES has a lower maximum dispatch cost than gas and wind + gas, and thus would have no difficulty defending a 90% capacity against either of the alternatives involving natural gas during periods of low demand. However, under our base case assumptions, wind + CAES would have difficulty

Table 5
Entry price sensitivities for wind and CAES

			$p_{\mathrm{NGeff}}^{\mathrm{wind}}$ (\$/GJ)	$p_{\mathrm{GHG}}^{\mathrm{wind}}$ (\$/tC$_{\mathrm{equiv.}}$)	$p_{\mathrm{NGeff}}^{\mathrm{CAES}}$ (\$/GJ)	$p_{\mathrm{GHG}}^{\mathrm{CAES}}$ (\$/tC$_{\mathrm{equiv.}}$)
Base case	See Table 3		7.083	115.7[a]	8.962	220.1[a]
Parameter	Value or change (±)	Units	$\Delta p_{\mathrm{NGeff}}^{\mathrm{wind}}$ (\$/GJ)	$\Delta p_{\mathrm{GHG}}^{\mathrm{wind}}$ (\$/tC$_{\mathrm{equiv.}}$)	$\Delta p_{\mathrm{NGeff}}^{\mathrm{CAES}}$ (\$/GJ)	$\Delta p_{\mathrm{GHG}}^{\mathrm{CAES}}$ (\$/tC$_{\mathrm{equiv.}}$)
CCR	–20	%	–1.041	–57.8	–1.379	–76.6
	+20		+1.041	+57.8	+1.371	+76.2
p_{NG}	–20	%	+0.999	+55.5	+1.009	+56.1
	+20		–0.996	–55.3	–0.998	–55.4
C_{C}, C_{E}	–20	%	0.000	0.0	–0.825	–45.8
	+20		0.000	0.0	+0.839	+46.6
C_{S}	0.1	\$/kWh	0.000	0.0	–1.257	–69.8
	0.5		0.000	0.0	–0.613	–34.0
	2		0.000	0.0	+0.980	+54.4
	10		0.000	0.0	+5.803	+322.4
C_{WP}	–20	%	–0.792	–44.0	–1.059	–58.8
	+20		+0.790	+43.9	+1.060	+58.9
C_{TL}	–20	%	–0.349	–19.4	–0.154	–8.6
	+20		+0.353	+19.6	+0.154	+8.6
C_{SC}, C_{CC}	–20	%	+0.019	+1.0	+0.814	+45.2
	+20		–0.028	–1.5	–0.792	–44.0
f_{W} (wind power class)	500 (3)	W/m^2	+0.725	+40.3	+1.182	+65.7
	800 (5)		–0.429	–23.8	–0.144	–8.0
k[b]	1.5		+0.259	+14.4	+0.952	+52.9
	3.0		+0.253	+14.0	–0.103	–5.7
θ	10	h	+0.020	+1.1	–0.662	–36.8
	60		–0.002	–0.1	+1.337	+74.3
D_{TL}	0	km	–1.713	–95.2	–0.778	–43.2
	500		–0.356	–19.8	–0.169	–9.4
	1000		+0.359	+19.9	+0.167	+9.3
	1500		+1.083	+60.2	+0.507	+28.2
r_{rate}	1.4		–0.194	–10.8	–0.487	–27.1
	1.6		+0.300	+16.6	+0.598	+33.2
$E_{\mathrm{o}}/E_{\mathrm{i}}$	–20	%	0.000	0.0	+1.202	+66.8
	+20		0.000	0.0	–0.901	–50.0
CF	–10	%	–0.130	–7.2	–0.709	–39.4
	+10		+0.001	+0.1	+0.758	+42.1
HR_{CAES}	–10	%	0.000	0.0	–0.649	–36.1
	+10		0.000	0.0	+0.759	+42.2
HR_{CC}	–10	%	–0.746	–41.4	–1.443	–80.2
	+10		+0.727	+40.4	+1.710	+95.0
HR_{SC}	–10	%	+0.019	+1.0	–0.016	–0.9
	+10		–0.041	–2.3	+0.032	+1.8
r_{min}	–100	%	0.000	0.0	–0.010	–0.5
	+100		0.000	0.0	+0.031	+1.7
l_{line}, l_{conv}	–50	%	–0.228	–12.7	–0.216	–12.0
	+50		+0.179	+9.9	+0.194	+10.8
Quadrature sum[c]			±2.156	±119.8	±4.112	±228.4

[a] p_{GHG} assumes $p_{\mathrm{NG}} = \$5/\mathrm{GJ}$.
[b] v_{avg} held constant at base case value.
[c] Average absolute change for each parameter category added in quadrature.

Table 6
Total and dispatch costs for alternative generation options

Technology	CF (%)	GHG emissions ($gC_{equiv.}$/kWh)	$0/t$C_{equiv.}$	$100/t$C_{equiv.}$	$0/t$C_{equiv.}$	$100/t$C_{equiv.}$
			Total cost at base case capacity factor (¢/kWh)		Dispatch cost (¢/kWh)	
Average coal plant[a]	—	276	—	—	2.16	4.93
Coal IGCC, CO_2 vented[b]	85	237	3.96	6.33	1.80	4.17
Coal IGCC, CO_2 capture and storage[b]	85	53	—	6.14	—	3.36
Gas[c]	90	120	4.54	5.74	3.48	4.69
Wind + gas[c]	90	73	5.09	5.82	0.86 to 3.48[d]	0.86 to 4.69[d]
Wind + CAES[c]	90	32	5.99	6.30	0.83 to 2.35[d]	0.83 to 3.15[d]

[a]For a $1.4/GJ coal price, a ¢0.67/kWh variable O&M cost, and a 34.3% power plant efficiency—the average projected for US coal plants in 2020 (EIA, 2005).

[b]IGCC costs are based on Williams (2004) adjusted for the financing rules of the current study, a $1.4/GJ coal price, and (in the CO_2 capture and storage case, which involves capturing CO_2 accounting for 85% of the carbon in the coal) storage in an aquifer 2 km underground located 200 km from the power plant. The capacities, overnight capital costs, and efficiencies of the IGCC plants are 827 MW, $1135/kW, and 38.0% for the CO_2 venting option and 730 MW, $1428/kW, and 31.5% for the CO_2 capture and storage option. The dispatch cost for the CO_2 capture and storage option includes the total cost of CO_2 transport and storage (at $9/t$CO_2$).

[c]For the optimized base case systems described in the present study, with $5/GJ gas price, 650W/m^2 wind resource, and 750 km HVDC transmission line.

[d]Dispatch cost varies depending on plant operation. *Wind+gas:* For wind park exactly meeting demand (here assumed 2 GW), dispatch cost is ¢0.86/kWh (variable O&M of wind park + TL losses). For CC gas turbine supplementation, dispatch cost is ¢3.48/kWh ($0/t$C_{equiv.}$) or ¢4.69/kWh ($100/t$C_{equiv.}$) (variable O&M of CC + fuel cost + GHG cost). For SC gas turbine supplementation, dispatch cost is 4.83 ¢/kWh ($0/t$C_{equiv.}$) or 6.52 ¢/kWh ($100/t$C_{equiv.}$). CC turbine dispatch cost is shown, as SC turbine contributes a minor amount of generation (2.2% in base case) and would not be a deciding factor at the low grid system demand levels relevant to the defense of a 90% system capacity factor. *Wind+CAES:* For wind park exactly meeting demand, dispatch cost is 0.83 ¢/kWh (note lower TL losses than for wind + gas). For wind park at maximum output, storing energy via CAES compressor, dispatch cost is ¢2.02/kWh (variable O&M of wind park and CAES compressor (assumed $\frac{1}{2}$ of total CAES variable O&M) + TL losses of transmitted wind). For CAES expander (no wind output), dispatch cost is ¢2.35/kWh ($0/t$C_{equiv.}$) or ¢3.15/kWh ($100/t$C_{equiv.}$) (variable O&M of CAES compressor + fuel cost + GHG cost + TL losses). These costs assume no foresight about future wind output and market electricity price.

sustaining a 90% capacity factor if there were competing coal options on the grid.

However, at $p_{GHG} = \$100/tC_{equiv.}$, wind + CAES has the least dispatch cost. Its closest competitor would be coal IGCC with CCS, but if dispatch competition were to force the capacity factor of that option down only modestly to 80%, its total *COE* would be higher than that of wind + CAES at 90% capacity factor.

At $p_{GHG} = \$35/tC_{equiv.}$, the dispatch cost for wind + CAES (¢2.6/kWh) would become the least for all the options. However, dispatch competition would have to force the capacity factor of a new coal IGCC plant with CCS down to 50% to make its COE the same as for wind + CAES at 90% capacity factor.

Thus, the prospects are good that wind + CAES baseload units would be strongly competitive with all the alternatives considered under a tough ($100/t$C_{equiv.}$) climate change mitigation policy, and in some circumstances even under a relatively modest ($35/t$C_{equiv.}$) policy. It should also be noted that although the outlook for providing baseload power with natural gas CC plants would typically be poor in regions where such plants must compete in dispatch with coal plants, natural gas would be highly competitive in providing baseload power via wind + CAES power plants, which could become a major market growth opportunity for natural gas in a world of high natural gas prices and a tough climate change mitigation policy.

3.3. Caveats

We have not considered all issues that might make wind + gas and/or wind + CAES less competitive than gas or other generation technologies. One issue is the seasonality of the wind resource, which is frequently anti-correlated with peak summer demand. Another concern focuses on outage rates: in addition to outages incurred when the wind is not blowing and the storage reservoir is empty, wind + CAES incurs additional outages due to maintenance like all generation systems. However, for both the wind + gas and wind + CAES systems, maintenance-related outage rates may be lower than those of the gas system if the maintenance for each component (wind park, and SC/CC or CAES plant) is performed when other system components are idle. In that case, if gas has a 90% capacity factor as we have modeled, then wind + gas will have a larger capacity factor (and therefore lower *COE*), because some of the maintenance can be performed while the wind turbines provide all the energy. However, wind + CAES, because outages occur *both* when the CAES reservoir is empty *and* during maintenance, will have a smaller capacity factor (and therefore higher *COE*). Along the same lines, the reliability of long-distance transmission lines, which we have assumed to be 100% reliable, may be lower, particularly as distance increases, which would raise the *COE* of both wind + gas and wind + CAES relative to gas.

Low-cost geologic reservoirs for CAES may not be available in all areas. While it is estimated that some form of suitable geologic storage is present in 75–80% of the US land area (EPRI-DOE, 2003), the type of geology varies: salt domes are prevalent in the Great Plains, Rocky Mountain and Gulf States regions; saline aquifers are ubiquitous in the Great Plains, Midwest and Appalachian regions; some regions contain only expensive hard rock; a few regions (the Southeast, much of California, and Nevada) contain no suitable geologic formations (Cohn et al., 1991). However, for the most part, the areas of potentially favorably geology overlap substantially with regions of high-quality wind resources. It remains to be determined from high-resolution geologic surveys just how prevalent this overlap is, though such surveys have not been completed for the US or any other region. Also, experience with the use of aquifers for CAES is limited.

There are also a number of options not considered in this study that may make wind parks and/or CAES more competitive than our analysis suggests. One option is simply to include a wider geographic diversity of wind parks, to increase wind's firm power and thereby decrease supplemental generation costs of both wind + gas and wind + CAES, though increased transmission costs may offset some of this advantage. Another option is to run the system in an intermediate-load configuration so as to provide power that has higher market value per unit energy than the baseload plant that is the focus of the present analysis. Indeed, all currently proposed CAES and wind + CAES projects focus on intermediate- or peak-demand markets (Wind, 2002; Bell et al., 2003; Desai and Pemberton, 2003). A third possibility is a reduction in the wind turbine rated power, which has been shown to lower the overall *COE* by reducing array losses and boosting the wind park capacity factor (Denkenberger, 2005). A final option is the incorporation of under-utilized gas turbine capacity into CAES systems, which under some circumstances might significantly lower capital costs for CAES (Nakhamkin et al., 2004).

4. Conclusions

This study has attempted to model the cost of producing baseload wind energy and its competition with fossil baseload energy. Under our base case assumptions with fixed 90% capacity factors for all the options, wind energy does not begin to compete with CC gas in terms of total cost of energy (*COE*) until effective fuel costs exceed \$7/GJ, and wind + CAES does not compete until above \$9/GJ. However, in real electricity markets, systems with lowest short-run marginal cost are dispatched first, maximizing capacity factors for those systems while diminishing capacity factors and raising the total cost of high-marginal cost competitors. We find that wind + CAES has the lowest short-run marginal cost above a GHG emissions cost of $\$35/\text{tC}_{\text{equiv.}}$ compared with gas, wind + gas, as well as a number of coal technologies; thus, wind + CAES will support very high capacity factors in a competitive market. Moreover, with a significant price on GHG emissions ($\sim\$100/\text{tC}_{\text{equiv.}}$), both wind + gas and wind + CAES will be important competitors in terms of total *COE* with coal integrated gasification combined cycle with carbon capture and storage (IGCC + CCS).

The use of energy storage, via CAES in this study, but in principle any cost-effective storage technology, also significantly boosts the ultimate penetration level for wind energy on an electric grid to 80 + %, compared to an upper limit of ~40% for wind with conventional backup power that is determined by wind's low capacity factor. This higher penetration level is possible by significantly increasing the wind park capacity relative to the capacity of the transmission line (in our optimization, this ratio is 2.22), and by using a large CAES storage reservoir (169 h at full CAES expander output). The "excess" wind capacity generates energy that is captured by CAES and retransmitted when needed, allowing the wind + CAES system to achieve a very high capacity factor (90%).

Shifting from fill-in backup to storage also significantly reduces the already-low GHG emissions from $76\,\text{gC}_{\text{equiv.}}/\text{kWh}$ (wind + gas) to $32\,\text{gC}_{\text{equiv.}}/\text{kWh}$ (wind + CAES). This emissions rate is about one-fourth of that for CC gas ($120\,\text{gC}_{\text{equiv.}}/\text{kWh}$) and almost one-tenth of that for a typical coal steam-electric plant ($276\,\text{gC}_{\text{equiv.}}/\text{kWh}$.) Only the emissions from coal IGCC + CCS plants are comparable ($\sim 50\,\text{gC}_{\text{equiv.}}/\text{kWh}$).

Our results depend, in some cases sensitively, on the choice of parameter values, and in addition, there are a number of unexplored issues that could either enhance or detract from the competitiveness of wind + CAES or wind + gas compared to other technologies. However, we feel that our analysis has generated a set of robust results that underscore the inherent attractiveness of these technologies with low emissions, low variable costs and falling capital costs that offer the potential to be highly competitive in baseload power markets. Additional modeling and case studies will be required to determine the role that wind energy can play in future electricity markets under various policy, cost and geographic circumstances.

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